BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

DOCKET NO. 2018-318-E

In the Matter of:	)	
	)	**DIRECT TESTIMONY OF**
Application of Duke Energy Progress, LLC	)	**JANICE HAGER**
For Adjustments in Electric Rate Schedules	)	**FOR DUKE ENERGY**
And Tariffs	)	**PROGRESS, LLC**

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND CURRENT POSITION.

A. My name is Janice Hager and my business address is 2049 Mount Zion Church Road, Alexis, North Carolina. I am President of Janice Hager Consulting, LLC.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I have extensive experience with Duke Energy Corporation over a 34-year career with the Company. I am a civil engineer, having received a Bachelor of Science in Engineering from the University of North Carolina at Charlotte. During my time at Duke Energy I was a registered professional engineer in North Carolina and South Carolina. I worked in Duke Power's (now Duke Energy Carolinas, LLC) Rates and Regulatory Affairs area for ten years, the last three of which I was Vice President of the department. Following the merger of Duke Energy and Progress Energy, Inc., I led Duke Energy's integrated resource planning process for all of the Company's regulated utilities, including Duke Energy Progress, LLC ("DE Progress") and Duke Energy Carolinas ("DE Carolinas"). At the time of my retirement in December 2014, I was Vice President of Integrated Resource Planning and Analytics for Duke Energy.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I have filed testimony and appeared before this Commission many times including on matters of Fuel Adjustment Clauses, Integrated Resource Planning, Certificates of Public Convenience and Necessity and other issues. I have also appeared before the North Carolina Utilities Commission, the Indiana Utilities Regulatory Commission, and the Federal Energy Regulatory Commission.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony describes and supports the allocation of DE Progress' electric operating revenues and expenses and original cost rate base assigned to the South Carolina retail jurisdiction and to each customer class according to the cost of service studies performed by the Company.

II. COST OF SERVICE STUDY OVERVIEW

Q. WHAT IS THE PURPOSE OF A COST OF SERVICE STUDY?

A. The purpose of a cost of service study is to align the total costs incurred by DE Progress in the test period, with the jurisdictions and customer classes responsible for the costs. The study directly assigns or allocates the Company's revenues, expenses and rate base among the regulatory jurisdictions and customer classes served by the Company based upon the service requirements of those respective jurisdictions and customer classes.

These service requirements are based on a number of factors, including differences in usage patterns and size.

Cost causation is a key component in determining the appropriate assignment of revenues, expenses and rate base among jurisdictions and customer classes. Under the principle of cost causation, costs are assigned to the specific jurisdictions and customer classes that "caused" such costs to be incurred.

Once all costs and revenues are assigned, the study identifies the return on investment the Company has earned for each customer class during the test period. These returns can then be used as a guide in designing rates to provide the Company an opportunity to recover its costs and earn its allowed rate of return.

Q. SHOULD THE COST OF SERVICE STUDY FULLY ALLOCATE COSTS AMONG JURISDICTIONS AND CUSTOMER CLASSES?

A. Yes. As the cost of service study is used as a guide in designing rates, all costs must be allocated to the appropriate jurisdiction and customer class. If any costs are omitted or remain unallocated, then the utility's rates will not allow for full recovery of the Company's operating expenses, including its approved cost of capital.

III. REVIEW OF DE PROGRESS' COST OF SERVICE STUDY

Q. HAVE YOU REVIEWED THE COST OF SERVICE STUDIES PREPARED BY DE PROGRESS FOR FILING IN THIS CASE?

A. Yes, as referenced by Witness Bateman in her pre-filed direct testimony, I have reviewed DE Progress' cost of service studies that were prepared and used in the rate design in this case.

Q. WHAT IS THE SOURCE OF THE COST COMPONENTS THAT ARE REFLECTED IN DE PROGRESS' COST OF SERVICE STUDY USED TO SUPPORT THE REQUESTED RATE INCREASE?

A. The cost of service study is based on the official accounting books and records of DE Progress, supported in this proceeding by Witness Doss. The cost components are comprised of the Company's electric operating expenses and original cost rate base and are based on the historical 12-month period covering January 1, 2017 through December 31, 2017 (the "Test Period").

IV. COST OF SERVICE STUDY PREPARATION

Q. PLEASE EXPLAIN HOW COSTS WERE ASSIGNED TO THE DIFFERENT JURISDICTIONS AND CUSTOMER CLASSES IN THE COST OF SERVICE STUDY IN SUPPORT OF THIS RATE CASE.

A. Generally, there are three key activities that occur when assigning costs in a cost of service study:

A. Costs are grouped according to their "function." Functions include production (generation), transmission, distribution, and customer service, billing and sales.

B. Functionalized costs are then grouped or classified based on the utility "operation" or service being provided and the related causation of the costs. Typical classifications include demand, energy, and customer-related costs.

C. Finally, the costs, which have been functionalized and classified, are allocated or directly assigned to the proper jurisdiction and customer class based on the manner in which the costs are incurred (*i.e.,* based on cost causation principles).

A. Functionalizing Costs

Q. PLEASE EXPLAIN HOW TO FUNCTIONALIZE COSTS.

A. The Company accounts for its costs using the Uniform System of Accounts ("USOA") of the Federal Energy Regulatory Commission ("FERC"). The USOA assigns the costs of the Company's plant investment into the primary categories of production (generation), transmission, distribution, and general and intangible plant. Similarly, the USOA categorizes the Company's operating costs into production, transmission, distribution, customer services, and administrative and general functions.

B. Classifying Costs

Q. PLEASE EXPLAIN HOW COSTS ARE CLASSIFIED.

A. Functionalized costs are classified according to their cost-causation characteristics. These characteristics are typically defined as demand-related, energy-related, or customer-related.

Q. PLEASE DEFINE DEMAND-RELATED COSTS.

A. Demand-related costs are costs incurred that vary in direct relationship to the kilowatts ("kW") of demand that customers place on the various segments of the system. Costs that are classified as demand-related include major portions of the Company's investment and related expenses in its production and transmission facilities and a significant portion of the investment and related expenses of its distribution system. These costs tend to remain constant over the short run and do not change based on the amount of energy consumed. These costs are often referred to as fixed costs.

Q. PLEASE DEFINE ENERGY-RELATED COSTS.

A. Energy-related costs are costs incurred that vary in direct relationship to the amount of energy or kilowatt hours ("kWh") generated and delivered. These costs are often referred to as variable costs.

Q. PLEASE DEFINE CUSTOMER-RELATED COSTS.

A. Customer-related costs are costs incurred as a result of the number of customers being served. Customer costs do not vary with the customers' volume of usage, but are related to the number of customers.

C. Allocation and Direct Assignment of Costs

Q. PLEASE EXPLAIN HOW COSTS ARE ALLOCATED AND DIRECTLY ASSIGNED.

A. Cost components identified as having a direct relationship to a jurisdiction or customer class are directly assigned to that jurisdiction or class before any allocations occur. For example, many distribution-related costs are directly

assigned to a jurisdiction based on their state location. For those costs as well as the remaining unassigned costs, specific allocation factors are developed that relate to the (1) demand, (2) energy, and (3) customer-related classifications identified above.

1. Demand Allocators

Q. WHAT DEMAND ALLOCATORS ARE USED TO ASSIGN DEMAND COSTS TO JURISDICTIONS AND CUSTOMER CLASSES IN THIS CASE?

A. There are two categories of demand-related costs used in the cost of service study:

a. Production & Transmission Demand - Production & Transmission demand costs are allocated using the Summer Coincident Peak ("SCP") method.

b. Distribution Demand - Distribution plant investments are directly assigned to the jurisdictions. At the customer class level, substations, and a part of poles, lines and transformers that have been designated as demand-related are allocated based on the Non-Coincident Peak Demand ("NCP").

a. Production and Transmission Costs

Q. PLEASE EXPLAIN THE CONCEPT OF ALLOCATING COSTS BASED ON COINCIDENT PEAK.

A. A coincident peak ("CP") allocator assigns the fixed, demand-related costs (for example, a portion of production and all transmission-related costs) to the

jurisdictions and customer classes in proportion to their respective contribution to the system's peak hourly demand during the Test Period. Each jurisdiction and customer class' cost responsibility (*i.e.*, the percentage of the fixed portion of production and transmission demand costs assigned to each jurisdiction and customer class) is equal to the ratio of their respective demand in relation to the total demand placed on the system. The cost of service study supporting the Company's proposed rate design in this proceeding allocates the fixed portion of production and transmission demand-related costs based upon a jurisdiction's and customer class' coincident peak responsibility occurring during the summer, otherwise known as the Summer Coincident Peak or SCP Allocator.

Q. WHEN DID THE SUMMER COINCIDENT PEAK DEMAND USED IN THIS STUDY OCCUR?

A. The DE Progress' summer peak generation and transmission demand used in this study occurred on Thursday, July 13th, at the hour ending 5:00 PM.

Q. WAS THE 2017 SUMMER PEAK ALSO THE SYSTEM PEAK FOR 2017?

A. No. The DE Progress system peak occurred on January 9th in the hour ending 8:00 AM. This DE Progress system peak was 14,407 MWs. The DE Progress system summer peak was 12,590 MWs. Given that the Company's generation and transmission investments being considered for cost recovery in this case were made based on summer peak planning, for consistency we have

continued to use the summer peak for cost allocation. However, Mr. Wheeler has given some consideration to the winter peak in rate design.

Q. WAS THE SUMMER CP TYPICAL WHEN COMPARED TO OTHER SUMMER CPs?

A, Yes. In 15 of the last 25 years, the Company's coincident peak occurred in the months of June through August. In all of the last 25 years, the summer peak has occurred between hour ending 3:00 PM and hour ending 5:00 PM. The 2017 summer peak is within the range of these past occurrences and it is therefore appropriate to assign fixed demand-related costs to the Company's jurisdictions and customer classes based upon the SCP.

b. Distribution Costs

Q. HOW ARE DISTRIBUTION COSTS ALLOCATED?

A. Most distribution investments are first identified and directly assigned to the state in which they are located. Then those distribution costs identified as customer-related are allocated based on customer allocation factors, as discussed below. The remainder of the distribution costs are designated as demand-related and allocated to the customer classes based on NCP demand allocators.

The NCP allocators are developed by taking the ratio of the non-simultaneous peak demands of the customers in each class whenever that peak occurred during the test period and comparing that to the sum of all customers' non-simultaneous peak demand. A number of different NCP allocators are developed to account for the different levels of the distribution

system where customers may take service (substation and below, primary and below, secondary, etc.). For example, only the NCP demand of customers who take service at secondary voltage are included in the development of the NCP allocator used to allocate secondary distribution lines and poles.

Q. WHY IS A NON-COINCIDENT PEAK USED FOR ALLOCATING DEMAND-RELATED DISTRIBUTION INVESTMENT?

A. Distribution facilities serve individual neighborhoods, rural areas, and commercial districts. They do not function as a single integrated system in meeting system peak demand. Instead, the distribution system serving each neighborhood, rural area, or commercial district must be able to meet the peak demand in the area it serves whenever the peak occurs. Accordingly, contribution to NCP is the appropriate measure of determining customers' responsibility for these costs because it best measures the factors that drive investment to support that part of the system.

2. Energy Allocators

Q. WHAT ALLOCATOR WAS USED TO ASSIGN ENERGY-RELATED COSTS TO JURISDICTIONS AND CUSTOMER CLASSES?

A. Energy-related costs reflect the variable cost of producing, transmitting and delivering electricity. Examples of costs allocated on this basis are fuel costs and variable production costs incurred at generating stations. DE Progress' kWhs of generation and deliveries during the Test Period have been used to allocate these variable costs. The kWh sales information is collected, and then adjusted for the level of losses attributable to each class and jurisdiction, in

order to derive the level of kWhs at the generator attributable to that class or jurisdiction.

3. Customer Allocators

Q. WHAT TYPES OF COSTS HAS DE PROGRESS INCLUDED FOR ALLOCATION AS CUSTOMER-RELATED?

A. DE Progress has included operating expenses in FERC accounts 901-917. These expenses include the costs of the service drop and meter, meter reading, billing and collection, and customer information and services. In addition, DE Progress has included in this category a portion of distribution costs that the Company has identified as customer-related.

Q. HAS THE COMPANY CHANGED HOW IT HAS DETERMINED THE CUSTOMER-RELATED PORTION OF DISTRIBUTION COSTS SINCE THE LAST RATE CASE?

A. Yes. In DE Progress's last rate case, within distribution plant, the Company identified as customer-related and allocated based on a customer allocator meters and service drops (FERC Accounts 369 and 370) and a portion of transformers (FERC Account 368). The remaining distribution plant and associated costs were classified as demand related. In this case, the Company has also identified a portion of the costs for distribution lines and poles (FERC Accounts 364-367) that are customer-related.

Q. DO YOU BELIEVE INCLUSION OF A PORTION OF DISTRIBUTION LINE AND POLE COSTS IN CUSTOMER ALLOCATIONS IS REASONABLE AND APPROPRIATE?

A. Yes. The National Association of Regulatory Utility Commissioners (NARUC) Electric Utility Cost Allocation Manual (CAM) states that a portion of distribution costs related to FERC Accounts 364-368 are customer-related. These FERC accounts include the costs of poles, towers, fixtures, overhead and underground conductors, and transformers. The two-methods the CAM discusses for allocating these customer-related distribution costs are:

1) Minimum System Method (called Minimum-Size Method in the NARUC Manual); and

2) Zero-Intercept Method (called Minimum-Intercept Method in the NARUC Manual).

Both methods recognize that some portion of the distribution system is necessary to serve customers, regardless of whether they take any energy from the system. The Minimum System Method seeks to determine the minimum size distribution system that can be built to serve the minimum loading requirements of customers. The Minimum System Method develops the cost of the minimum set of distribution assets that would be needed to serve customers and allocates those costs based on the number of customers.

Similar to the Minimum System Method, the Zero-Intercept Method allocates a portion of the same distribution accounts on the basis of the number of customers. The Zero-Intercept method seeks to identify the portion

of distribution plant that is associated with no load using regression techniques.

Q. WHICH METHOD DID DE PROGRESS CHOOSE AND WHY?

A. DE Progress incorporated the concept of Minimum System into its COS Study for allocating costs to customers, which is appropriate for allocation of customer-related distribution costs. The zero-intercept method is generally considered to be a more complex and time-consuming methodology that often can produce results that are not materially different from the Minimum System method. The theory behind use of a Minimum System study is sound and consistent with cost causation, which is the foundation of COS studies. DE Progress' Minimum System Study allowed DE Progress to classify the distribution system into the portion that is customer-related (driven by number of customers) and the portion that is demand-related (driven by customer peak demand levels). Every customer requires some minimum amount of wires, poles, transformers, etc. just to receive service; therefore, every customer "caused" DE Progress to install some amount of such distribution assets. The concept DE Progress used to develop its Minimum System Study was to consider what distribution assets would be required if every customer had only some minimum level of usage (e.g., 1 light bulb). This methodology allows the utility to assess how much of its distribution system is installed simply to ensure that electricity can be delivered to each customer, if and when the customer chooses to use electricity. Once minimum system costs

have been identified, all distribution costs over the minimum system costs and direct assignments are allocated based on demand.

Q. WHAT WAS THE IMPACT OF THE METHOD THE COMPANY PREVIOUSLY USED TO ALLOCATE DISTRIBUTION COSTS?

A. As I noted earlier, DE Progress previously included the costs for meters, service drops and included a portion of transformers as the customer-related portion of distribution plant. I will call this method the Basic Customer method. This method produces a lower allocation to customer-related costs and thus, in rate design, a lower fixed customer charge. As mentioned previously, all costs are allocated; the issue is which are designated demand-related, energy-related, or customer-related. By designating a lower amount as customer-related, the Basic Customer method necessarily allocates more costs to the demand-related portion of distribution costs. A higher allocation to demand-related costs means higher demand charges for customers whose electric rate includes demand charges and higher energy charges for those without demand charges. Without the use of the Minimum System allocation methodology, low use customers avoid paying for the infrastructure necessary to provide service to them which is counter to cost causation principles.

Q. WHAT IS THE PRIMARY BASIS UPON WHICH WITNESS WHEELER BASED THE BASIC FACILITIES CHARGES?

A. Witness Wheeler relied upon costs allocated as being customer-related in the Cost of Service Study in developing his recommendation regarding the Basic Facilities Charges.

4. Grid Improvement Plan Allocations

Q. CAN YOU EXPLAIN THE ALLOCATION FACTORS USED FOR THE COMPANY'S PROPOSED GRID IMPROVEMENT PLAN STEP-UP RATE?

A. Yes. As explained in the testimony of Witness Bateman, the Company is proposing to implement step-up phases in base rates for certain grid improvement investments in the transmission and distribution systems. In general, these investments will follow the same cost causation principles that are applied to the investments recovered through base rates. These investments should therefore be allocated to each customer class based upon the transmission and distribution allocation factors used for these assets in the cost of service study. Specifically, for the transmission investments the transmission peak demand allocators were applied. For distribution investments, a composite allocator of distribution plant, excluding extra facilities and Accounts 371 and 373, is appropriate. Because none of the projected investments will be extra facilities or street or area lighting, it was appropriate to exclude these accounts from the composite allocator.

5. Excess Deferred Income Tax Rider Rate Allocations

Q. CAN YOU EXPLAIN THE ALLOCATION FACTORS USED IN THE COMPANY'S EXCESS DEFERRED INCOME TAX RIDER?

A. Yes. The Company has allocated the benefits in the Excess Deferred Income Tax ("EDIT") rider to the classes based on the Accumulated Deferred Income Tax ("ADIT") allocator. I have reviewed this allocation and believe it is reasonable based on cost causation principles. Since the EDIT amounts were previously part of ADIT as explained by Witnesses Bateman and Panizza, this is consistent with how the amounts were allocated prior to the federal tax rate change and reasonably reflect how the benefits were created.

6. Conclusion on Allocation Methodology

Q. ARE THE COMPANY'S CHOSEN METHODOLOGIES TO ALLOCATE ITS DEMAND-RELATED, ENERGY-RELATED AND CUSTOMER-RELATED COSTS REASONABLE AND APPROPRIATE UNDER THE CIRCUMSTANCES?

A. Yes, they are.

V. CONCLUSION

Q. DOES THE COMPANY'S COST OF SERVICE STUDY USED FOR THIS CASE PROPERLY DISTRIBUTE COSTS OF PROVIDING ELECTRIC SERVICE TO CUSTOMER CLASSES?

A. Yes, it does. The cost of service study provides a proper foundation for distributing costs among the jurisdictions and customer classes because it recognizes cost causation and distributes costs accordingly. This study also

provides a proper basis for determining cost-based rates and is a major component of fair and equitable rate design. The cost of service study also provides an accurate measure of profitability among classes of customers.

Q. DID YOU VERIFY THAT THE COST OF SERVICE INFORMATION YOU ARE TESTIFYING TO WAS USED IN DETERMINING HOW TO DESIGN PROPOSED RATES?

A. Yes. The South Carolina retail cost of service information, including the separation of the demand, energy, and customer components of cost, was used in developing the rate design proposed by DE Progress.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.